EVALUATING THE POTENTIAL IMPACT OF TRANSMISSION CONSTRAINTS ON THE OPERATION OF A COMPETITIVE ELECTRICITY MARKET IN ILLINOIS

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Overview

- Presentation provides and introduction to the study, with an emphasis on the UIUC portion.
  - ANL presentation will provide detailed results
- Overall purpose of study was to make an initial determination if the regional transmission system could support a competitive electricity market
  - Could a single company unilaterally raise prices
- UIUC portion of study focused mostly on the transmission system analysis.

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Assumed Transmission System Model

- Model was constructed from 2003 summer peak power flow case, with Illinois utility modifications.

- Original model included all of the Eastern Interconnect, while the study model was reduced in scope to cover a region roughly bounded by Minnesota, Missouri, Tennessee, Ohio and Michigan

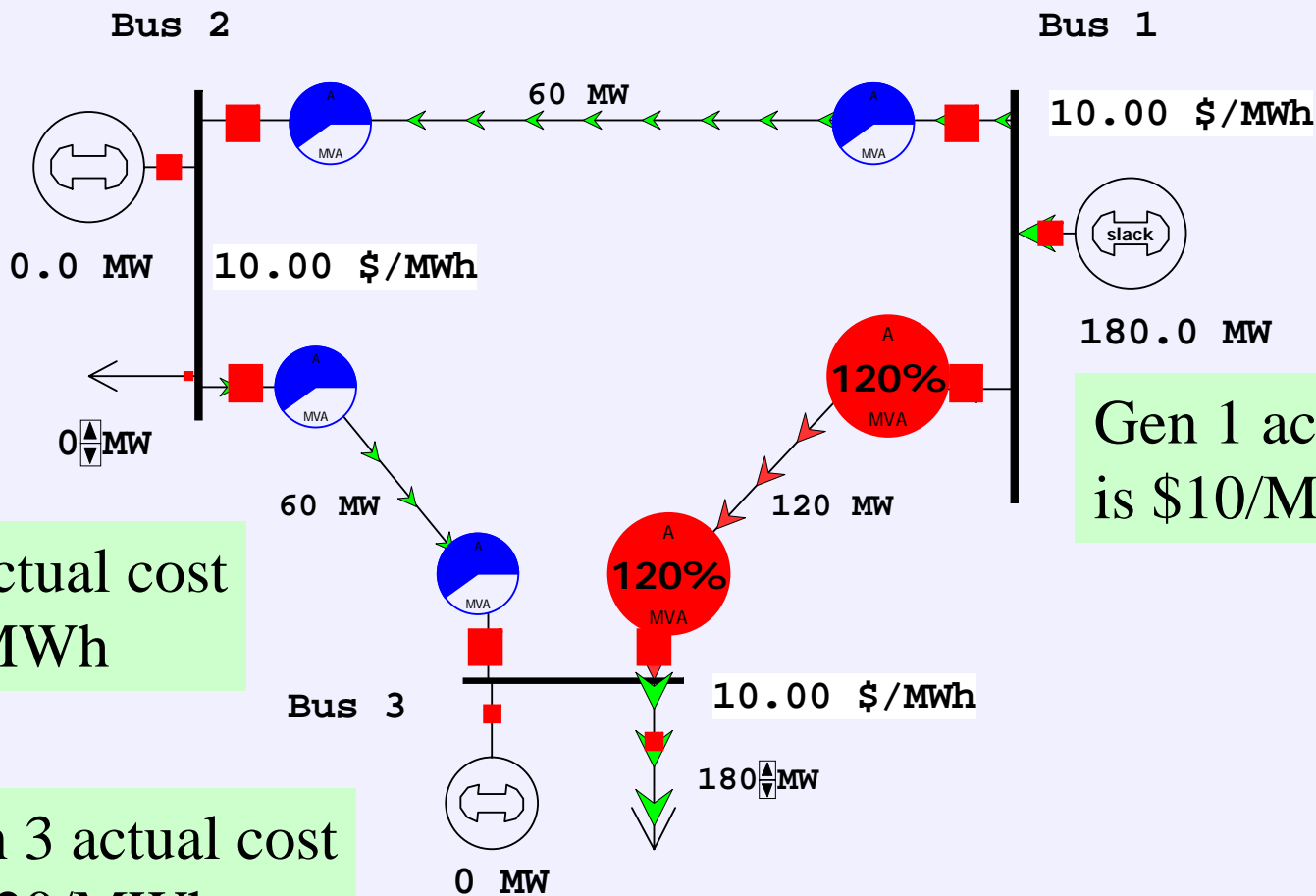 – full Illinois transmission system was included in the model

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Solution Approach:
A Unified LMP-Based Market

- Study approach was to do hourly simulations that sought to mimic how the system would be assumed in 2003 to be dispatched in 2007

  - Find least cost generation dispatch so that there were no transmission system overloads

  - Initially, generators' costs were assumed to be their actual costs; later studies allowed modified generator cost curves for profit maximization

- LMPs (locational marginal prices) tell the cost to supply electricity to different grid locations
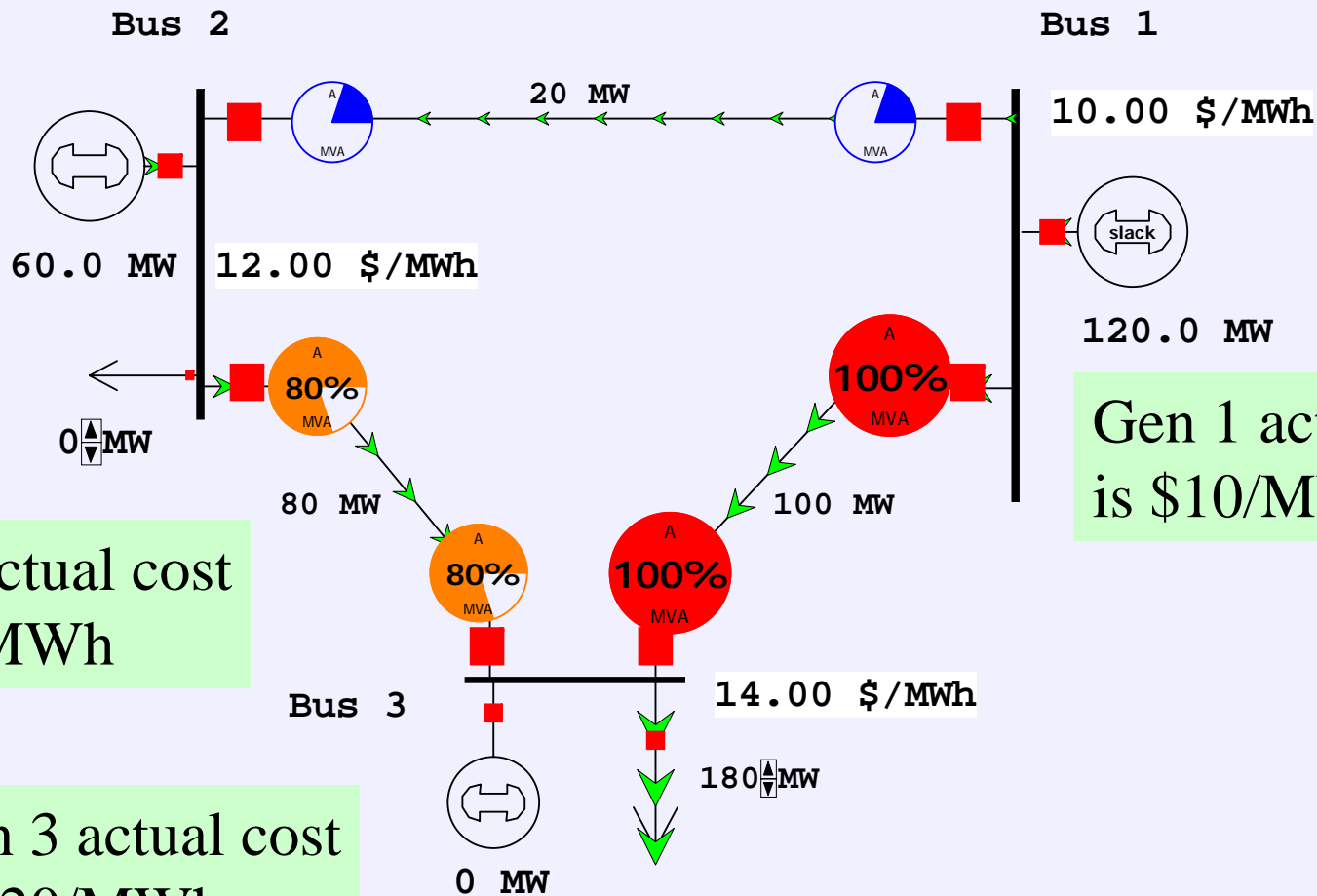
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Three Bus LMP Example:
No Transmission Limits

Bus 2

60 MW

Bus 1

10.00 $/MWh

0.0 MW   10.00 $/MWh

slack

180.0 MW

Gen 1 actual cost
is $10/MWh

0 MW

120%

120 MW

60 MW

Gen 2 actual cost
is $12/MWh

120%

10.00 $/MWh

Bus 3

180 MW

0 MW

Gen 3 actual cost
is $20/MWh

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Three Bus LMP Example: With Transmission Limits

Bus 2

Bus 1

20 MW

10.00 $/MWh

60.0 MW   12.00 $/MWh

120.0 MW

Gen 1 actual cost is $10/MWh

0 MW

80%

80 MW

80%

100%

100 MW

Gen 2 actual cost is $12/MWh

100%

Bus 3

14.00 $/MWh

180 MW

Gen 3 actual cost is $20/MWh

0 MW

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Three Bus LMP Example: With Market Power at Bus 3
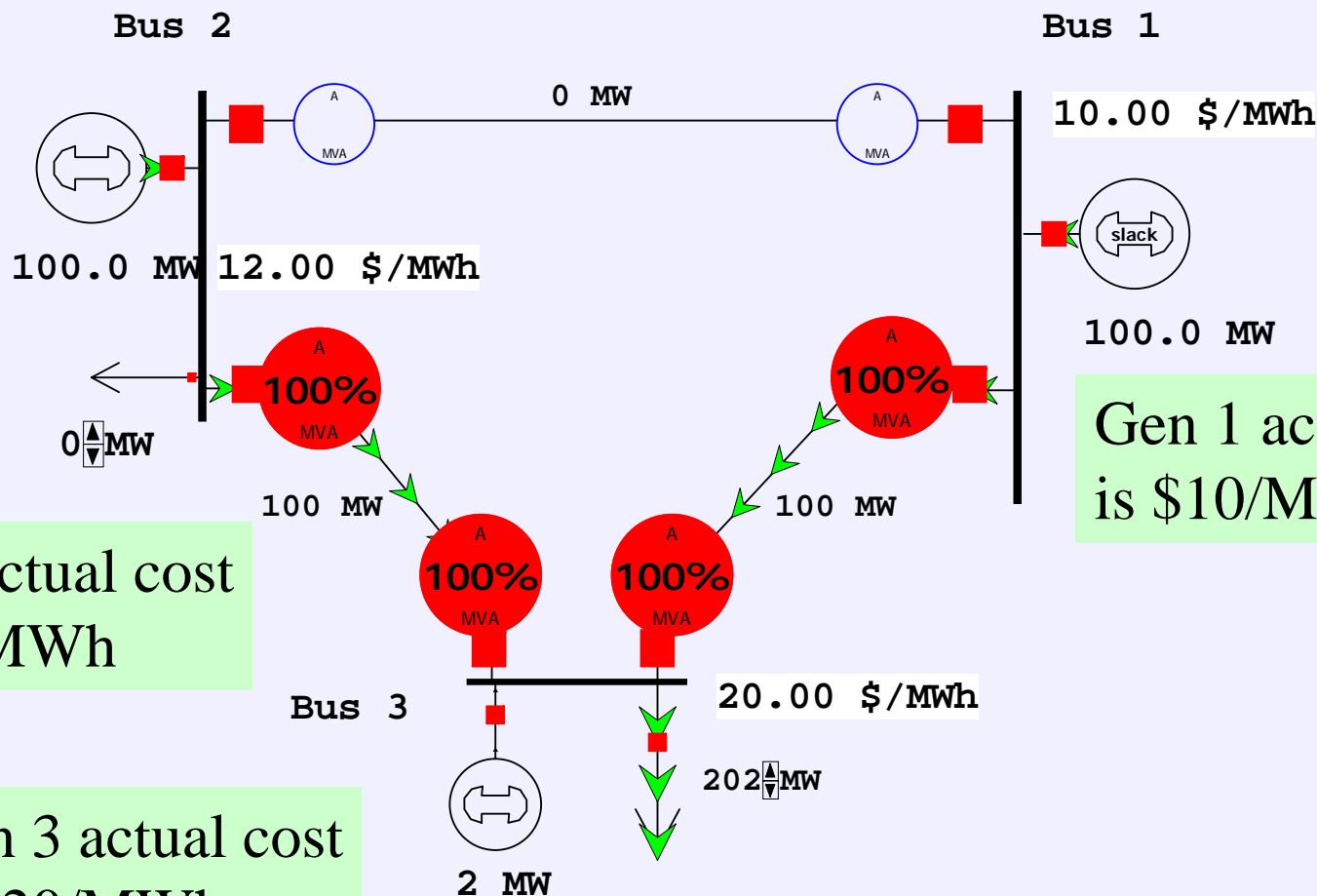
Bus 2

0 MW

Bus 1

10.00 $/MWh

100.0 MW 12.00 $/MWh

100.0 MW

100%

100%

0 MW

Gen 1 actual cost is $10/MWh

100 MW

100 MW

Gen 2 actual cost is $12/MWh

100%

100%

Bus 3

20.00 $/MWh

202 MW

Gen 3 actual cost is $20/MWh

2 MW

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Three Bus LMP Example:
Bus 3 Gen Exploiting Market Power
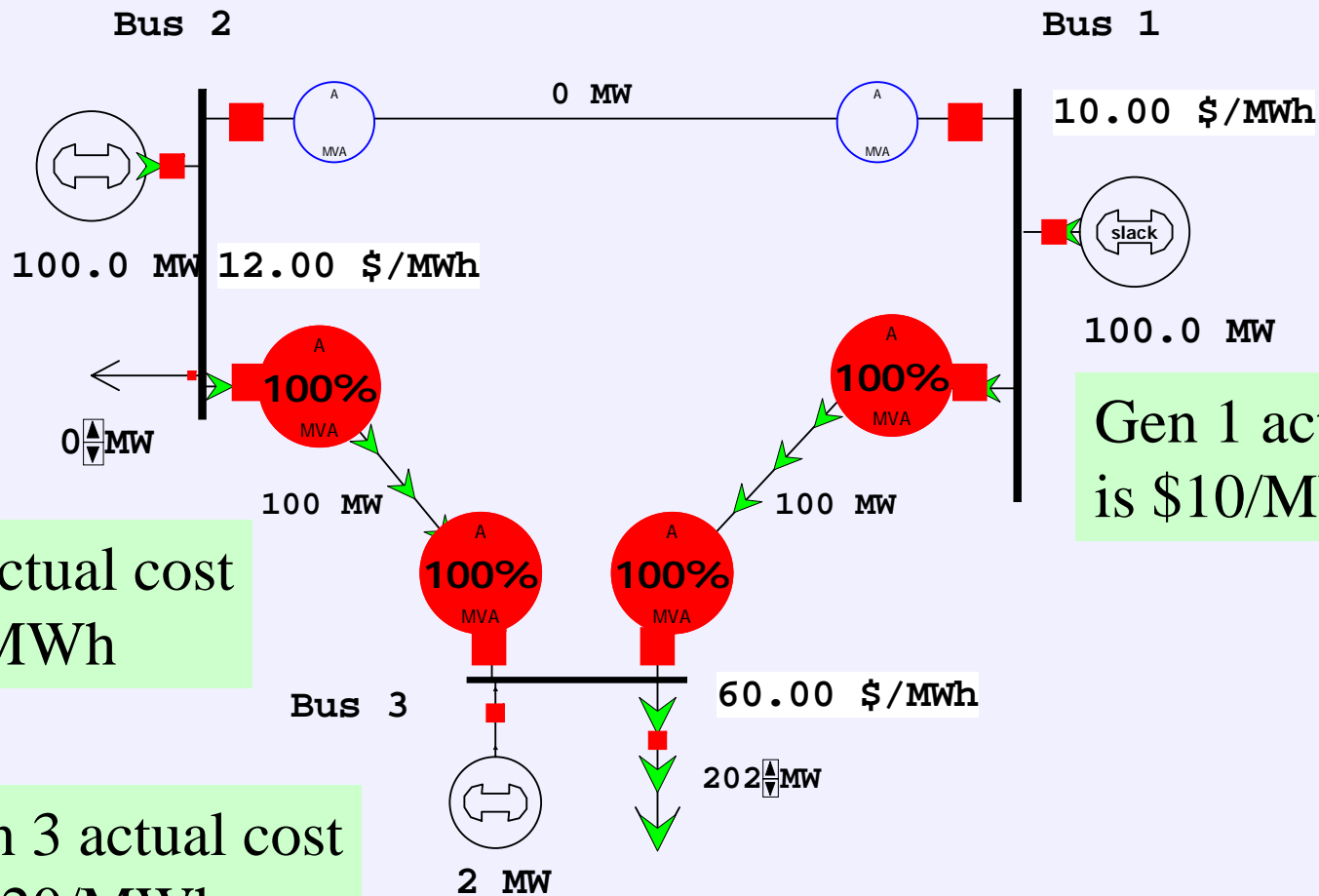
Bus 2

Bus 1

0 MW

10.00 $/MWh

100.0 MW 12.00 $/MWh

100.0 MW

100%

100%

Gen 1 actual cost is $10/MWh

0 MW

100 MW

100 MW

100%

100%

Gen 2 actual cost is $12/MWh

Bus 3

60.00 $/MWh

202 MW

2 MW

Gen 3 actual cost is $20/MWh

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Solution Overview

- Approached used was hourly security constrained optimal power flows (SCOPFs)
- Initial SCOPFs were solved for each hour for the assumed 2007 conditions with the assumption that all generators submitted bids equal to their actual marginal costs
  - data was calculated and stored for each bus for each hour → hundreds of millions of numbers

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Interpretation of Results

- A point to stress in understanding the results is the details matter. For example, whether a particular line was binding, and hence the cause of high LMPs in a region, was dependent upon many factors, including the line's limit, the contingency set, and availability of post-contingent operating procedures

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Example of Results: LMP Contour for 90% Load, Marginal Cost Bids
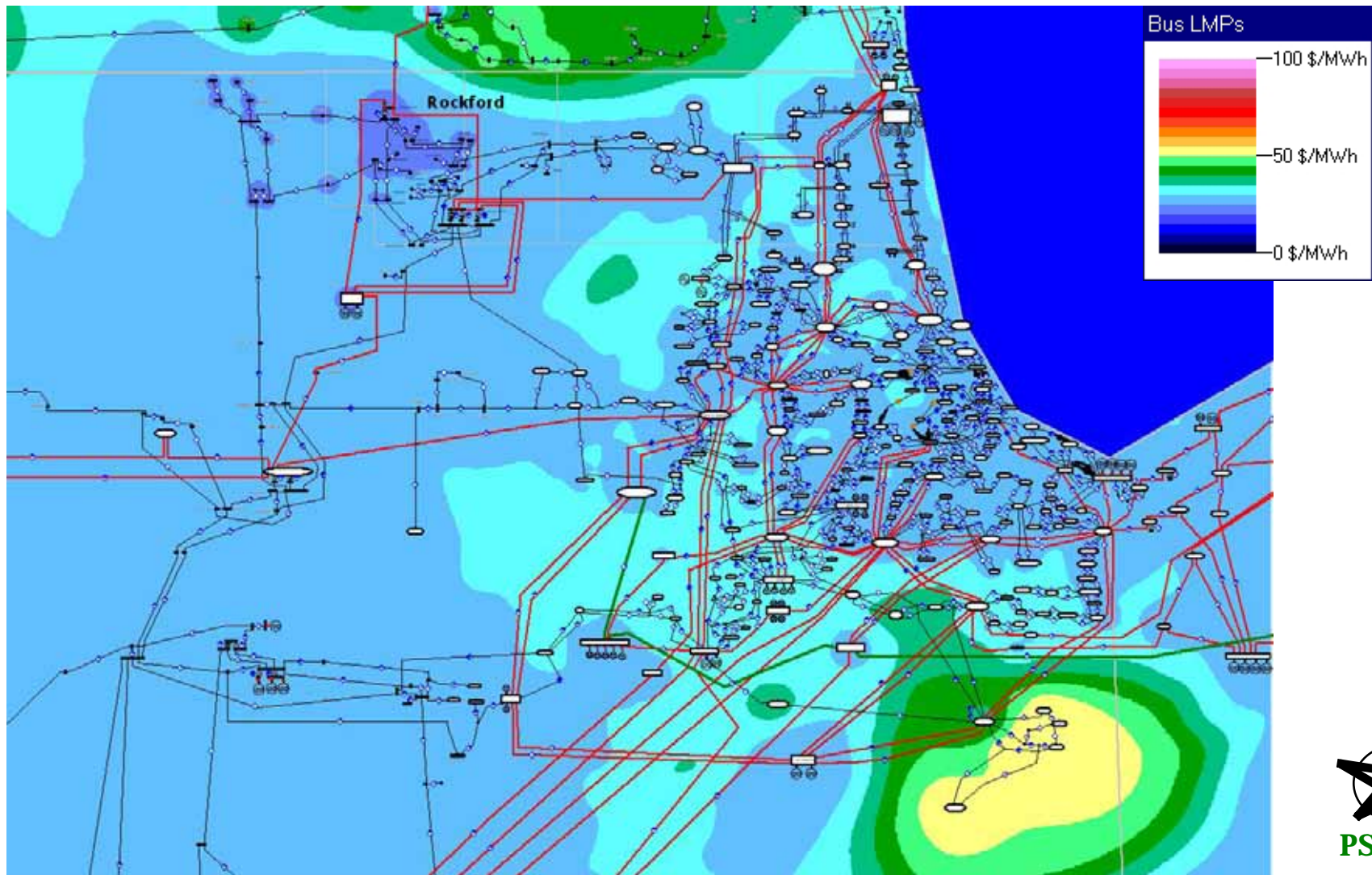
Previous Slide with Some Generator Bids at 10 times Marginal Cost

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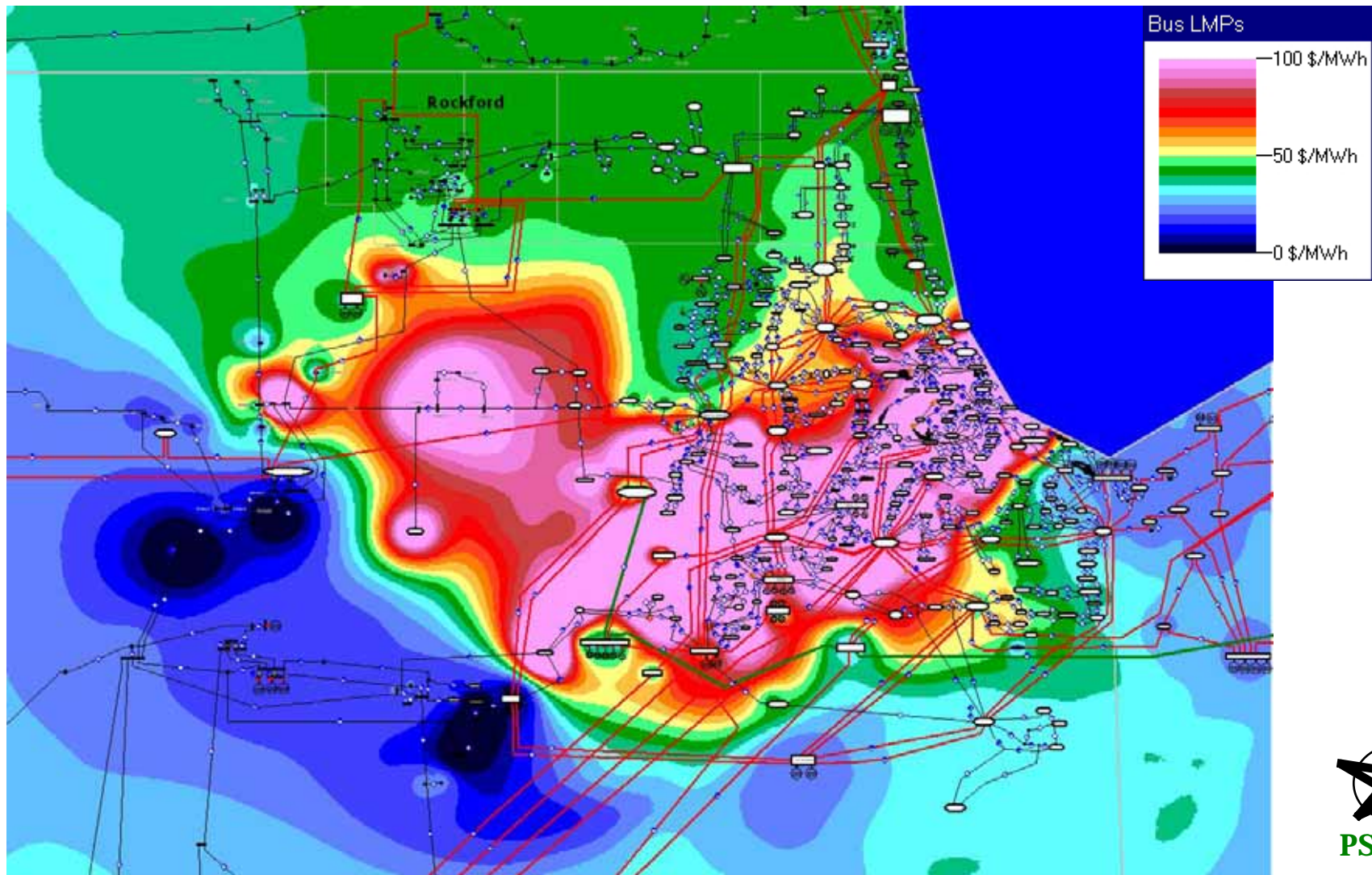
A Detailed Discussion of Results is Provided in the ANL Presentation

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